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PUBLIC SERVICE COMMISSION

In the Matter of the Value of Distributed Energy Resources Working Group Regarding Value Stack	**Case 15-E-0751** **Matter 17-01276**

Proposal for Distribution and Transmission Value for Distributed Energy Resources (DERs), and DRV/LSRV Modifications

Clean Energy Parties: Solar Energy Industries Association, Alliance for Clean Energy New York, Coalition for Community Solar Access, Natural Resources Defense Council, New York Solar Energy Industries Association, Pace Energy and Climate Center, and Vote Solar

Dated: June 7, 2018

Comments to New York State Department of Public Service

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I. INTRODUCTION AND SUMMARY

The Clean Energy Parties appreciated the opportunity to present on April 6, 2018. These comments clarify and expand on our proposal regarding the distribution and transmission value for distributed energy projects, and our recommendations for improving DRV and LSRV valuation and compensation.

The promise of distributed energy resources is the ability to lower emissions, drive economic investments, yield ratepayer savings, and increase grid resiliency. Distributed energy resources can provide these multitude of benefits while providing an alternative to utility distribution investments. Indeed, even without proactive efforts to align utility investment with distributed energy deployment, energy efficiency and distributed generation have avoided the need for billions of dollars in generation, transmission, and distribution infrastructure. However, the current structure of the VDER tariff threatens the promise of distributed energy resources by providing distorted short-run price signals based on inaccurate proxies for utility investments. This creates an uneven standard for distributed energy resources versus utility investments and would result in an inaccurate and unfinanceable tariff if carried into Phase 2. It is for this reason that our April 6th presentation laid out the universe of values needed to improve the scope of – and methodologies for calculating – the credit that VDER resources receive for the transmission and distribution benefits they provide. Please note that this paper and our April 6 presentation do not address changes to environmental and generation-level benefits that we expect will be reviewed as part of the Phase 2 process.

The utility distribution planning process underlies efforts in New York, California, and a growing list of states to align distributed energy resource deployment with distribution grid needs, in addition to realizing the transmission, environmental, generation, and other benefits of their deployment. In the annual distribution planning process, utility distribution system engineers review recent peak loads and projected load growth across individual distribution planning areas and, using power flow modeling software, determine whether the circuit loads in each distribution planning area are likely to violate operating criteria (thermal, voltage, safety/protection) at some point over the planning horizon. Based on the timing, type, and magnitude of the need, the utility will pursue an operational change (e.g., reconfiguring the distribution grid through switches), plan an investment, or monitor the need over subsequent planning cycles.

For example, utility power flow modeling may suggest that undervoltages will occur during a local peak load. Power flow modeling may suggest the violation occur between hours 4,375-4,380 four years out (July 1, 2022). Based on that need, the utility may, for example, reconductor feeders in the area. The peak may ultimately occur on July 1, 2022; more likely it will occur in some other hour – maybe early September, maybe August, maybe it will be late afternoon rather than midday. From the utility operations standpoint, the modeled problematic hour is all that matters since the infrastructure installed will be available at all hours to meet the peak load, whenever it occurs. This investment will be recovered, with a rate of return, over the book value of the asset, even if the need that asset was deployed to meet fails to materialize.

Similarly, the New York Independent System Operator (NYISO) conducts a biannual assessment of the transmission security for the bulk power transmission system based on ten-year load forecasts and considering future generator retirements and other system changes. If a transmission security-related reliability or public policy transmission need is identified, the NYISO begins the process of identifying potential solutions. If a transmission solution is selected and built in response to a reliability or public policy need, the transmission project becomes eligible for cost allocation and recovery under the NYISO's tariffs. As with distribution system investments, the cost of the transmission project will be recovered, with a rate of return, over the book life of the asset, even if the need fails to materialize.

Distributed energy resources enter the distribution planning process in two ways: 1) avoiding projects from ever materializing in a distribution plan by reducing peak loads and 2) avoiding, delaying or minimizing the cost of projects that ultimately do arise in the distribution planning process. The same logic applies for other parts of the utility system: DERs avoid the need for new generation assets and transmission lines and, in the case of the transmission planning process, could be used to avoid planned transmission projects.

VDER should capture the long run value of distributed energy resources to avoid utility investments while providing their myriad other benefits. Indeed, it is the ability of DERs to avoid projects from materializing in distribution and transmission plans that is one of the key reasons for providing a credit that reflects their long-run value. But instead in Phase 1, VDER created a standard to which the otherwise applicable utility investment would never be able to – or expected to – meet. VDER's treatment of DERs is comparable to if a utility could only deploy a new substation transformer if it could predict the peak load day in each of the coming years. In keeping with this analogy, a VDER-tariffed substation transformer would no longer be in the rate base after three years because it and other upgrades eliminated the need it was installed to address.

Utilities, understandably, do not rely on such short-run compensation methods to deploy generation, transmission, or distribution infrastructure, and it is unrealistic and unfair to expect distributed energy resources to do so. The proposal outlined below begins what we hope will be an issue-by-issue discussion in coming Working Group meetings on how to better align VDER compensation with distribution needs.

II. OUR RECOMMENDATIONS

Building on the Clean Energy Parties' April 6 presentation, this paper highlights specific areas in need of further significant improvement, analysis, and work before the Commission renders a VDER Phase 2 decision.

As a procedural matter, we respectfully request that the issues discussed below be examined through additional working group meetings before the Phase 2 methodologies become set in stone. There remains a significant lack of transparency regarding the assumptions, data, and methodologies used to calculate the avoided transmission and distribution value. Stakeholders do not have confidence that the current method captures the full value that DERs provide to the grid as envisioned by the REV proceeding. And in some cases, entire areas of value are ignored under current practice.

Our recommendations fall into three categories: improvements to the marginal cost of service (MCOS) studies, long-run transmission benefits, and modifications to the DRV and LSRV mechanisms.

1. MCOS Modifications

The DRV and LSRV are based on the utilities' MCOS (or similar) studies,[1] and therefore the data, assumptions, and methodologies behind the MCOS studies must be made transparent, standardized, and improved. We offer the following MCOS-related recommendations:

- The working group should address the issue of consistency across MCOS methodologies.
- The utilities' load forecasts relied upon for projecting capital investment needs should be made available, including all relevant data and assumptions, and the load forecasts should be consistent at a minimum with the electrification expected in the New York State Energy Plan.
- For the purposes of valuing DERs, forecasts of incremental DER should be removed from the utilities' baseline load forecasts. As recognized by CHG&E, "incorporating into forecasts DERs that have not yet been built or installed can dilute the location value signal and potentially slow down their adoption." [2]
- The utilities' capital investment plans that underlie the MCOS analysis should be provided, along with the planning thresholds and other criteria used, and the time period over which costs have been amortized. The information provided should include brief descriptions of the projects contained in the capital investment plans, project classifications (e.g., load growth-related, replacement of aging infrastructure, etc.), and the rationale for including or excluding projects in the MCOS and subsequent calculation of the DRV and LSRV. The reporting format for this information should be standardized.

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[1] Rather than relying on a marginal cost of service study, Central Hudson employed a probabilistic forecasting methodology to develop avoided distribution and transmission costs. This study was filed in its Distribution System Implementation Plan (DSIP).

[2] Central Hudson Initial Distributed System Implementation Plan June 30, 2016 p. 65.

- The MCOS study time horizons should be consistent and extended to at least ten years.[3] Shorter time horizons will not capture a reasonable minimum extent of projects avoided by DERs.
- The MCOS studies should include all relevant benefits, including investments not related to load growth, but which could be avoided (or rendered less costly) due to DERs. These benefits could include reduced equipment replacement or upgrade costs, reliability and regulation benefits, new information from situational awareness through communication and sensing equipment, and new reliability services such as back-tie services.

2. Modifications to Account for the Long-Run Value of Avoided Transmission

We believe that it is essential that in Phase 2, the Commission look beyond the near-term congestion and transmission charges that are already included in the LBMP components of VDER Phase 1. As with distribution infrastructure, it is feasible to estimate transmission needs based on a combination of historical evidence and projected future changes to the transmission grid. With the correct signal through an avoided transmission value in the VDER stack, it may be possible to eliminate or mitigate these additional transmission needs by DER deployment.[4] For example, as the result of load reductions from energy efficiency and behind-the-meter solar, California cancelled 18 transmission projects and pared back 21 other projects, reducing transmission capital costs by over $2.6 billion.[5] Similar benefits that occur in New York should be recognized and included as an additional component of the VDER value stack.

To calculate the long-run avoided transmission costs, we recommend using a regression methodology developed by National Economic Research Associate (NERA) as a preliminary step towards calculating a system wide value of avoided transmission costs until a more precise, location-specific valuation methodology has been determined.

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[3] NYSEG and RG&E MCOS Responses, March 6, 2018 uses a five-year horizon.

[4] Currently NYISO is considering transmission projects totaling approximately $1 billion. *See:* Fan, Dawei and Timothy Duffy. AC Transmission PPTN: Evaluation Updates. Presentation to ESPWG/TPAS, May 10, 2018.

[5] CAISO, 2017-2018 Transmission Plan, March 14, 2018, pages 2-3.

A more sophisticated approach to quantifying the avoided cost of transmission investments could be implemented through the NYISO stakeholder process using a transmission security analysis. The analysis would utilize appropriately-designed load-flow modeling (including but not necessarily limited to assessment of N-1 violations) under a counterfactual scenario in which no new DERs are implemented, and then would estimate the cost of transmission upgrades required under the counterfactual relative to the base case. Currently NYISO performs a biannual Reliability Needs Assessment (RNA), in which similar scenarios are analyzed for resource adequacy. For example, the most recent Reliability Needs Assessment report includes a High Load Forecast Scenario that excludes energy efficiency programs and retail solar PV programs from the baseline peak forecast. The result is a 2,962 MW increase in peak load in the year 2026 as compared with the base case forecast of the same year.[6] Unfortunately, the RNA performs this analysis only for generation capacity needs and does not carry the analysis through to an assessment of how transmission needs or costs would be impacted.

The Clean Energy Parties recommend using the best available methodology for estimating avoided transmission costs. At present, the NERA regression methodology provides a reasonable approximation of such avoided costs. However, if a more sophisticated analysis were performed by NYISO, we would recommend using the results of that analysis.

3. <u>Modifications to the DRV and LSRV Mechanisms</u>

In order to be accurate yet financeable, the division of the full possible avoided distribution and transmission costs into DRV and LSRV should be made more transparent and the rationale standardized, the conversion of those values into megawatts of capacity need should be shared and also standardized, the amortization period for the avoided cost should align with the compensation period and a fixed payment rate should be used during that period, and the performance requirements should align with actual distribution planning parameters and should

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[6] New York Independent System Operator, "2016 Reliability Needs Assessment," October 18, 2016, iv.

not impose unnecessary performance risk for individual DERs. Therefore, we make the following recommendations:

- The manner in which MCOS values are separated into DRV and LSRV, and then converted into megawatts of capacity and DRV and LSRV payments, should be made more transparent, with calculations provided and reviewed publicly. Specifically, the utilities' rationale and methodology for classifying certain avoided costs as avoidable/not avoidable by DERs and thus eligible/ineligible for DRV vs LSRV should be made explicit, the methodology for calculating MW caps should be defined in detail, and supporting data and assumptions for these calculations (such as planning thresholds) should be provided to stakeholders.
- The utilities should ensure that the amortization period for the avoided cost matches the period over which a DER is eligible to receive compensation. For example, if the DER is eligible to receive DRV payments for 10 years, then the amortization of the net present value of avoided costs should be over 10 years in order to ensure that the DER is fully compensated for the value provided. This same principle should be applied to LSRV payments.
- DERs that have already been installed should not face variability in the maximum DRV and LSRV compensation that they could receive during the amortization period that aligns with the compensation period, as they have contributed to the reduction in marginal cost that is represented in revised MCOS studies. Without the installation of these DERs, the marginal cost would remain high. DERs should be paid for that service over a specific period of time as a fixed maximum payment per year subject to successful performance.
- The backward-looking top 10-hour performance requirement should be replaced with a forward-looking analysis based on probabilistic effective load carrying capability (ELCC) analysis or a similar methodology. Specifically, in the interim between now and the Phase 2 tariff's completion, we recommend that the Commission consider adopting the Capacity "Alternative Two" 460-peak-hour methodology for all DER currently in development as a proxy for the currently-forecasted system peaks.

- To the extent they are not already doing so, the utilities should move to a probabilistic forecasting methodology that identifies the primary hours that drive system investments (potentially covering 300-500 hours). These hours should then be communicated to DER providers via a tariff, allowing DER providers to respond to those price signals by designing and installing new DERs capable of responding during the identified hours.

III. PROPOSED MODIFICATIONS TO MARGINAL COST OF SERVICE STUDIES

The utilities' marginal cost of service (or similar) studies provide the foundation for the current DRV and LSRV mechanisms. However, these studies require a number of improvements, including using more appropriate and standardized electric load forecasts and study time horizons, and capturing the full range of DER distribution system benefits.

In the September 2017 Order on Phase One Value of Distributed Energy Resources Implementation Proposals, the Commission, recognizing that there is room for improvement in the Phase One methodologies, set forth the goals of improving and standardizing the utilities' MCOS analyses underlying DRV and LSRV.[7] The Commission specifically deferred the consideration of the variation in the marginal cost of service studies and methodologies among the utilities to Phase 2. However, to date, the Phase 2 process has not adequately addressed the improvements necessary to the MCOS studies in order to establish accurate LSRV and DRV avoided costs.[8] Below we discuss the shortcomings of these studies, followed by our proposal for improvement.

[7] September 2017 Order, p. 11-12 and 15.

[8] CHG&E is the exception in that it has developed a probabilistic study of location-specific avoided transmission and distribution costs.

A. Issues Associated with Current Marginal Cost of Service Methods

1. Lack of Appropriate Standardization and Clarity of Load Forecasts

The calculations of DRV and LSRV within the MCOS are dependent on data from the load forecasts made in the distribution planning process. The assumptions underlying the load forecasts are key to identifying future investments in load-related infrastructure. However, the fundamental methodologies used in load forecasting vary significantly across the utilities and lack clarity regarding important assumptions. This lack of consistency and clarity in calculation of load forecasts may undervalue the related capital expenditures required for load growth.

- Except for CHG&E, the utilities use deterministic methodologies in forecasting future load growth. Unlike probabilistic methodologies, these deterministic forecasting methodologies do not account for uncertainty in load growth.
- The peak load forecast methodologies and assumptions are also inconsistent across utilities. For National Grid, the proposed MCOS study includes a 95/5 forecast corresponding to a 1-in-20 year event.[9] Within its Distribution System Implementation Plan (DSIP), Con Edison uses the "prior summer's actual daily peak demands and adjusts the overall season's peak demand to a thermal design condition based on a one-in-three probability of meeting a temperature variable (TV) design condition of 86°F."[10] Although not clear, it appears that the Con Edison MCOS Study is based on these peak load forecast assumptions.
- It is not clear the extent to which the utilities' forecasts include load growth from electrification including from electric vehicles and adoption of heat pumps for buildings. While many (but not all) of the utilities include an electric vehicle forecast in their DSIP, these forecasts are not necessarily consistent with New York Energy Plan and state policy goals. For example, CHG&E's forecast is

[9] Towards a "Value of D": National Grid's Marginal Avoided Distribution Cost Update, February 9, 2018, Slide 7.
[10] Con Edison, Distributed System Implementation Plan (DSIP), June 30, 2016, Pg. 21.

based on recent EV growth rates, rather than the growth required to meet the Zero Emissions Vehicles (ZEV) target.[11] National Grid makes several forecasts based on Annual Energy Outlook scenarios, as well as the ZEV target,[12] but it is unclear which forecast (if any) are used to inform system investments in its MCOS.

- It is not clear whether all utilities are removing forecasted DER from their baseline load forecasts. As recognized by CHG&E, "incorporating into forecasts DERs that have not yet been built or installed can dilute the location value signal and potentially slow down their adoption."[13] Thus, failure to remove future DER from the utilities' baseline load forecasts would undervalue the benefits of the resources that are not currently online. For example, Con Edison has specifically mentioned that it uses both existing and future DER within the load forecast.[14] It is not clear however, if the future forecasted DER resources have been removed from its baseline load forecasts in assessing the locational value of future DER resources.

2. Lack of Proper Study Time Horizons

To date, calculations of DRV and LSRV have been based on MCOS study time horizons that are inconsistent and inappropriately short, with some of the utilities relying on five-year MCOS studies.[15] The MCOS study provides the foundation for the determination of future avoidable costs and a study horizon of only five years would underrepresent and undercompensate, the full extent of projects avoided by DERs. This is because a five-year study period ignores significant investment that may be required (and that could be avoided) in year 6 and beyond. By taking only a very near-term approach to planning, it is likely that only a subset of avoidable projects are being identified, artificially reducing the megawatts of DER needed and

[11] CHG&E DSIP, Appendix N, Section N.2.
[12] National Grid 2016 Electric Peak Forecast, November 24, 2015.
[13] Central Hudson Initial Distributed System Implementation Plan June 30, 2016 p. 65.
[14] Con Edison O&R response to SEIA questions March 5, 2013.
[15] NYSEG and RG&E MCOS Responses, March 6, 2018 uses a five-year horizon.

in some cases the value of the DER per kW-year. At minimum, the study period should extend to ten years.

According to the utilities' February 9, 2018 presentation of proposed changes to the MCOS, National Grid and Con Edison plan to use a ten-year study horizon for the MCOS in the future.[16] We applaud National Grid and Con Edison for their proposal and urge them to move expeditiously. However, it remains unclear what study horizon NYSEG and RG&E propose to use. To accurately account for the full avoided costs of DER, it is essential that NYSEG and RG&E adopt a ten-year horizon, consistent with the remaining utilities' MCOS proposals.

The table below summarizes the diversity of assumptions and methodologies used by the utilities.

[16] National Grid, Towards a "Value of D": National Grid's Marginal Avoided Distribution Cost Update, Slide 8; Con Edison Marginal Cost Study Overview, Slide 3.

Table 1. Comparison of Utility-proposed Avoided T&D Methodologies for Phase Two

	CHG&E	Con Edison and O&R[17]	National Grid[18]	NYSEG and RG&E
Planning horizon	Unclear for Phase Two; in Phase One, 10 years[19]	10 years	10 years	Unclear for Phase Two; in Phase One, 3 to 5 years[20]
Locational granularity	Substation[21]	Load area	Substation / distribution feeders	Substation / primary feeder (differentiated by voltage level) [22]
Types of investment considered	Network investment associated with load growth only	Network investment associated with load growth from new and existing customers, asset replacement	Network investment associated with "avoidable demand growth" (i.e., from existing customers)	Network investment associated with load growth (possibly in high value areas only)[23]
Deterministic or probabilistic	Probabilistic[24]	Deterministic	Deterministic	Deterministic
Load forecast parameters	50/50[25]		95/5	

Note: Where detail was missing from a utility's February 2018 presentation, we referred to previous VDER implementation plan filings.

[17] The Brattle Group. Con Edison Marginal Cost Study Overview. February 9, 2018.

[18] National Grid. Towards a "Value of D": National Grid's Marginal Avoided Distribution Cost Update. February 9, 2018.

[19] CHG&E. Workplan of Central Hudson Gas & Electric Corporation to Consider Additional Potential Sources of Value Created by Distributed Energy Resources. April 24, 2017. P. 6.

[20] NERA. Proposed Workplan and Timeline for Developing Granular Marginal Distribution Cost Estimates for DER Compensation in NYSEG and RG&E Service Territories. April 24, 2017. P. 4.

[21] Central Hudson Avoided T&D Study. Slide 3.

[22] NERA, Using Marginal Cost Studies to Estimate Demand Reduction Value (DRV) and Location System Relief Value (LSRV). February 9, 2018. Slide 3.

[23] NERA. Proposed Workplan and Timeline for Developing Granular Marginal Distribution Cost Estimates for DER Compensation in NYSEG and RG&E Service Territories. April 24, 2017. P. 1.

[24] Central Hudson Avoided T&D Study. Slide 3.

[25] CHG&E. Workplan of Central Hudson Gas & Electric Corporation to Consider Additional Potential Sources of Value Created by Distributed Energy Resources. April 24, 2017. P. 8.

3. Failure to Include All Relevant Benefits

An additional shortcoming of the MCOS studies is that they generally restrict the scope of distribution system benefits provided by DERs to those associated with load growth. Distribution benefits should include investments avoided beyond those for load growth. These benefits include reduced equipment replacement or upgrade costs, reliability and regulation benefits, new information from situational awareness through communication and sensing equipment, and new reliability services such as back-tie services. Such potential benefits were recognized by the Commission in its March 2017 order, in which it wrote: "Realizing other sources of distribution value – such as the marginal value of distribution voltage and reactive power or the short-run marginal value of distribution constraint management – present increasing complexity and will require continued investment to implement increasingly sophisticated solutions, the Commission requires a detailed schedule from each utility for unlocking those values."[26]

Reduced Replacement or Upgrade Costs

Future age-related upgrades or replacements expenditures that are not directly associated with load growth could potentially be reduced in the long term through demand reduction and should be included in the DRV compensation tariff. For example, Con Edison has outlined in its DSIP that it has a budget category for replacement of equipment (i.e., investments to replace failed and degraded equipment). Despite the fact that these equipment replacements may not be tied to load growth or system expansion expenditures, the reduction in demand caused by DER may reduce the investment required for these replacements, since the replacement equipment would be smaller and less expensive due to reduced load.

Reliability and Regulation

DER equipped with smart inverters can provide reliability and regulation services to the grid. Inverters that meet the new IEEE 1547-2018 standard will be required to have "smart" functions and a uniform set of capabilities, including reactive power support for voltage regulation. However, the utilization of some of these smart inverter functions is not free, as it

[26] March 9, 2017 Order, page 117.

could reduce output and result in reductions in generator performance under certain circumstances. The ability to utilize these optional capabilities can provide significant additional benefits to the grid that are not currently captured in the VDER stack, and which therefore do not encourage the activation of some of these smart inverter functions. As an example of the benefits provided by smart inverters, Illinois has required utilities to offer a $250/kW rebate for being able to control smart inverters during reliability events.[27]

Situational Awareness

Smart inverters provide benefits in terms of "situational awareness." Often utilities are required to make additional investment in infrastructure that allows them to acquire and provide data to grid operators regarding visibility into the grid that would facilitate insight into the grid operation. Smart inverters would be able to provide this additional capability to utilities by acquiring necessary data. This would avoid otherwise necessary utility investments to attain that data, including the installation of sensing and communications equipment. As an example, the Hawaii Public Utilities Commission denied the Hawaiian Electric Company ("HECO") $736 million worth of grid modernization investments under the premise that

> Third-party providers could be utilized to perform many grid modernization functions; indeed, these entities are already measuring energy use, generation, and power quality for large numbers of the HECO Companies' customers. Leveraging this existing, third-party infrastructure may well provide a lower cost and lower risk alternative for some components of grid modernization, particularly in the early years of the overall grid modernization initiative…. [T]he Companies should be exploring ways to leverage existing infrastructure and strategically and holistically integrate this growing portfolio of DER in order to lower risk to customers while increasing flexibility in grid modernization investment and deployment.[28]

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[27] 220 Illinois Compiled Statutes Section 16-107.6, available at http://www.ilga.gov/legislation/ilcs/fulltext.asp?DocName=022000050K16-107.6

[28] HI PUC, Docket No. 2016-0087, Order No. 34281 at 38–39 (Jan. 4, 2017), available at https://www.hawaiianelectric.com/Documents/about_us/investing_in_the_future/dkt_2016_0087_20170104_order_34281.pdf

Non-Capacity Reliability

Measures of customer interruption are often utilized for justification of grid modernization investments. Customer interruption costs vary widely across and within rate classes, with some customers (such as large C&I customers manufacturing goods) having much higher interruption costs than others (such as residential customers). However, while the benefits of improved reliability are disproportionately realized by a relatively small number of customers, utility investments in Fault Location and Service Restoration, automated switching, and other distribution automation investments are socialized.

Customer investments in distributed energy resources (particularly storage) that can island from the grid and provide electricity service during outages, can reduce customer outages. These lower outage rates may then reduce the number of investments proposed by the utilities to improve reliability. Quantification of such benefits could begin with utility infrastructure investments that have been approved or proposed in rate cases for the purpose of improving reliability and resiliency.

Enhanced CVR Energy Savings

Distributed energy projects with smart inverters also have the potential to provide additional energy savings beyond conventional Conservation Voltage Reduction (CVR) programs. A study conducted by NREL outlined these benefits, showing that HECO experienced a 1.37% increase and PG&E experienced a 0.44% increase in the CVR energy savings by deploying smart inverter autonomous volt-VAR control.[29]

New Reliability Back Tie Services

Additional grid stabilization is provided by DER through reliability "back tie" services. Reliability back tie services reduce demand to improve local distribution reliability and resiliency. This benefit was recognized by the Competitive Solicitations Working Group in

[29] Photovoltaic Impact Assessment of Smart Inverter Volt-VAR Control on Distribution System Conservation Voltage Reduction and Power Quality https://www.nrel.gov/docs/fy17osti/67296.pdf

California, which states that these services "can be provided by a single DER resource and/or an aggregated set of DER resources that are able to reduce the net loading on specific distribution infrastructure coincident with the identified operational need in response to a control signal from the utility."[30]

B. PROPOSED MODIFICATIONS TO MARGINAL COST OF SERVICE METHODS

1. Electric Load Forecasts and Avoidable Investments

The Clean Energy Parties recommend that a detailed, DPS-led regulatory process be initiated to consider and determine methodologies and assumptions that all utilities should use in developing load forecasts for their MCOS or DER distribution valuation study. This standardization and transparency is critical for developing an accurate study that values the locational impacts of DER.

Factors that should be considered within this process include:

- Only existing DER should be included in baseline forecasts so as not to under-estimate the locational value of future DER; and
- Assumptions regarding future electrification of end-uses (e.g., electric vehicles and heat pumps), and whether they adequately take into account the most recent NY State Energy Plan and state-driven targets.

2. Study Horizon and Probabilistic Modeling

The Clean Energy Parties recommend that MCOS studies extend for at least 10 years, and that the utilities adopt probabilistic modeling techniques. Probabilistic modeling is better suited to a longer time horizon, because it better recognizes increasing uncertainty further out in time.

[30] Competitive Solicitation Framework Working Group Final Report, Docket R.14-10-003, August 1, 2016, p. 12.

3. Inclusion of All Relevant Benefits

In addition to costs from avoided load growth, the Clean Energy Parties recommend that the utilities evaluate the value of reduced equipment replacement or upgrade costs, reliability and regulation benefits, new information from situational awareness through communication and sensing equipment, and new reliability services such as back-tie services brought by DERs. Indeed, the Joint Utilities stated their intention to conduct an analysis of these capabilities in their April 2017 Work Plan, which describes a currently ongoing study of smart inverter performance through smart meter settings and advanced monitoring across a range of feeder types, PV system sizes, loads, locations, equipment, and configurations.[31] Once these technologies have been implemented and are being used for reliability and in planning, DER should be compensated from the new, resulting stream of benefits that they provide. National Grid calculates avoided outage costs to quantify reliability and resiliency benefits of resources and has referenced "limited instances when DER can provide local loads in the event of blackouts which results in avoided outages."[32] This could be used as a starting point to calculate the reliability benefits offered by DER.

Although we do not doubt the sincerity of the utilities' interest in learning how best to incorporate these technologies, we note that there remain legacy business model realities that may not align with the utilities' interest in moving quickly to plan for and quantify the benefits that these technologies can provide. If the state is to achieve the Commission's vision for a more efficient, flexible, and dynamic distribution grid, it is important that the Commission and Staff exercise leadership in setting aggressive, but achievable timelines for the utilities to conduct this important work.

[31] Joint Utilities. April 24, 2017 Work Plan. P.5.

[32] National Grid Distribution System Implementation Plan, June 30, 2016, Pg. 47.

IV. PROPOSAL TO FULLY ACCOUNT FOR TRANSMISSION VALUE

The benefits associated with avoiding or deferring future transmission expenditures can be reflected in marginal transmission costs. DERs can and do reduce future transmission costs beyond short-run transmission congestion costs reflected in the LBMP.

Transmission upgrade needs are driven by peak load on each piece of equipment on the transmission system.[33] However, transmission costs are typically lumpy – once the incremental load representing "the straw that breaks the camel's back" is imminent, a significant new piece of infrastructure must be installed at considerable cost. Because of economies of scale, the new infrastructure will be capable of handling significantly more load. Looking forward in time, load growth might ultimately require a new wire, transformer, or other transmission equipment one year, within the next five years, or even a decade or more in the future. Therefore, any new on-peak load between the present and the prospective capital investment contributes to that need; any on-peak load reduction helps defer that need.

In the short-run, the transmission benefits associated with DERs manifest themselves in the locational marginal prices and generation capacity auction prices, (i.e., the LBMP and ICAP prices). These prices reflect zonal-level congestion, thereby indicating the value of transmission capacity.[34] Under VDER, DER are compensated for reducing these congestions charges as part of the energy portion of the value stack, and are thus being compensated for near-term transmission relief.

A long-run view, however, should include additional transmission costs that are not captured by congestion in the production simulation models. Within the MCOS study conducted for Con Edison, it is noted that "that the congestion adder included in locational market prices does not necessarily reflect the full incremental cost of new transmission assets as transmission may be required for load-relief reasons that are not related to LBMP differences." This full

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[33] The hours associated with the upgrade needs are typically correlated with regional system peak load and NYISO-wide coincident peak, although detailed study may reveal differences across the NYISO system.

[34] E3, "The Benefits and Costs of Net Energy Metering in New York," December 11, 2015. Figure 15 and Figure 16.

incremental cost of transmission assets should be included within the DRV/LSRV compensation stack. For example, numerous large transmission projects have been approved in recent years, and additional projects are likely as unit retirements and changes in load require additional multi-billion dollar investments in transmission infrastructure.[35] NYISO also continues to plan for numerous system constraints that could be solved or alleviated through the construction of new transmission or—alternatively—through the adoption of DER.[36]

Because of their distributed nature, DER can reduce or eliminate the need for many of these transmission projects, as the CAISO has recently concluded with respect to the California grid.[37] We believe that it is essential that in Phase 2, the Commission look beyond the near-term congestion and transmission charges that are already included in the LBMP components of VDER Phase 1. As with distribution infrastructure, it is feasible to estimate transmission needs based on a combination of historical evidence and projected future changes to the transmission grid. With the correct signal through an avoided transmission value in the VDER stack, these additional transmission needs can be mitigated or eliminated by DER deployment. Therefore, these benefits should be recognized and included as an additional component of the VDER value stack.

In order to include in long run avoided transmission costs, a regression methodology developed by National Economic Research Associate (NERA) can be a preliminary step towards calculating a system wide value of avoided transmission costs until a more location specific valuation methodology has been determined. The method requires data regarding the cumulative planned capacity and cumulative capital expenditure data (historical/forecasted). The regression develops a relationship between the cumulative planned capacity (kW) and the capital expenditure/investment ($) to obtain a marginal investment value in $/kW. The marginal value is then converted into a levelized revenue requirement which can be used as a system wide value or

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[35] Currently NYISO is considering approximately $1 billion in transmission projects. *See:* Fan, Dawei and Timothy Duffy. AC Transmission PPTN: Evaluation Updates. Presentation to ESPWG/TPAS, May 10, 2018.

[36] See generally E3, "The Benefits and Costs of Net Energy Metering in New York," December 11, 2015, at 18-39.

[37] As the result of load reductions from energy efficiency and behind-the-meter solar, California cancelled 18 transmission projects and pared back 21 other projects, reducing transmission capital costs by over $2.6 billion. *See:* CAISO, 2017-2018 Transmission Plan, March 14, 2018, pages 2-3.

more regional value for the long-term avoided transmission costs. This methodology captures all the drivers that necessitate transmission infrastructure investments. These drivers could be a variety of reasons such as peak load growth, reliability concerns, and/or investments that are made for economic reasons (e.g., to reduce market costs for electricity by reducing congestion). If located in beneficial areas, DERs can potentially reduce all of these investment drivers. SCE has utilized this methodology in calculation of the incremental cost of adding delivery related capacity using ten years of historical data and five years of forecasted data for its 2018 General Rate Case.[38]

A more sophisticated approach to quantifying the avoided cost of transmission investments could be implemented through the NYISO stakeholder process using a transmission security analysis. The analysis would utilize appropriately-designed load-flow modeling (including but not necessarily limited to assessment of N-1 violations) under a counterfactual scenario in which no new DERs are implemented, and then would estimate the cost of transmission upgrades required under the counterfactual relative to the base case. Currently NYISO performs a biannual Reliability Needs Assessment, in which similar scenarios are analyzed for resource adequacy. For example, the most recent Reliability Needs Assessment report includes a High Load Forecast Scenario which excludes energy efficiency programs and retail solar PV programs from the baseline peak forecast. The result is a 2,962 MW increase in peak load in the year 2026 as compared with the base case forecast of the same year.[39] Unfortunately, the RNA performs this analysis only for generation capacity needs and does not carry the analysis through to an assessment of how transmission needs would be impacted or the cost of additional transmission capacity to meet additional needs.

The Clean Energy Parties recommend using the best available methodology for estimating avoided transmission costs. At present, the NERA regression methodology provides a reasonable approximation of long-term transmission avoided costs. However, if a more sophisticated analysis were performed by NYISO, we recommend using the results of that analysis.

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[38] SCE, Phase 2 of 2018 General Rate Case Marginal Cost and Sales Forecast Proposals, Pg. 28 – 30.

[39] New York Independent System Operator, “2016 Reliability Needs Assessment,” October 18, 2016, iv.

V. BRINGING THIS VALUE TO MARKET: PROPOSED MODIFICATIONS TO DRV AND LSRV

A. GREATER CLARITY IN HOW MCOS IS CONVERTED TO DRV AND LSRV, AND THEN INTO MEGAWATTS OF CAPACITY

In addition to the above issues with the MCOS studies, the methodology for dividing the resulting total avoided cost into DRV and LSRV needs clarification and standardization, and then the conversion of those values into megawatts of capacity should also be standardized. Specifically, this work would include:

- **Need for Consistent Rationale for Dividing Avoided Cost Into LSRV vs DRV**
  - Both National Grid and O&R used "engineering judgement" to select an LSRV compensation that is 50% higher than the MCOS system wide value.[40] A rationale for setting the LSRV at 50% higher has not been provided.
  - Con Edison has established a threshold criterion for classification of an area as LSRV: if load reaches or exceeds 98% of the current capability for high voltage sub-transmission lines or 90% of distribution area capability by 2021 then the location would be classified as LSRV area.[41] Con Edison has used "engineering judgement" in choosing this threshold and has provided no clarity on reasons for selection.
  - Some utilities also differ in the treatment of locations that have been identified as Non-Wires Alternative ("NWA") locations. CHG&E has

[40] Value of Distribution Implementation Proposal of New York State Electric and Gas Company and Rochester Gas & Electric Company, May 1, 2017.

[41] Consolidated Edison Company of New York, Inc. Implementation Proposal for Value of Distributed Energy Resources Framework.

removed potential NWAs from receiving LSRV compensation until they become active.[42] It is not clear if the capacity for this NWA project has been procured. Utilities should not remove projects from receiving LSRV compensation until the capacity has been procured and the project is active.

    - National Grid on the other hand has scaled the loads on a substation level out to 2020 (a much shorter time frame than CHG&E) and these were screened against their planning ratings in projecting capital expenditures and for selection of the LSRV areas.[43] It is unclear however, what these planning ratings are and whether they are consistent with other utilities.

- **Conversion of LSRV and DRV values into MW of DERs**
    - Greater transparency and standardization is needed regarding how the MW caps on the amount of DER that would be eligible to receive LSRV are established. For example, O&R states that the caps were determined by "identifying the amount of load relief that would be required to bring LSRV areas into alignment with design standards or to operate constrained areas at improved capacity and thermal operating levels, based upon future forecasted loads in the upcoming ten-year planning period, and based on system analysis that determined areas operating with higher exposure and operating risk under contingency conditions." This description alone is insufficient to provide stakeholders with certainty that the caps are correctly determined. The Clean Energy Parties recommend that the utilities provide additional data and documentation identifying the design standards used, the forecasted loads for specific areas of the utility's territory, and other relevant assumptions or information. Ensuring that the cap is set correctly is essential to procuring the amount of DERs necessary for avoiding infrastructure investments.

[42] Value of Distribution Energy Resources Implementation Proposal, Central Hudson Gas & Electric Corporation May 1, 2017.
[43] National Grid, Implementation Proposal for the Value Stack Component of VDER Phase One Tariff**,** May 1, 2017.

B. AMORTIZATION PERIOD FOR THE AVOIDED COST SHOULD ALIGN WITH THE COMPENSATION PERIOD AND A FIXED PAYMENT RATE SHOULD BE USED DURING THAT PERIOD

It is unclear based on the MCOS studies and the implementation proposals from utilities other than CHG&E as to what amortization period for avoided costs is used for DER compensation through DRV and LSRV.[44] The number of years used in amortizing the avoided costs will impact the value of DER significantly and should be presented with clarity and transparency within the MCOS and subsequent DRV/LSRV calculations.

To remedy this, the utilities should provide much greater information regarding their assumptions, underlying data, and calculations. Further, the utilities should ensure that the amortization period matches the period over which a DER is eligible to receive compensation. For example, if the DER is eligible to receive DRV payments for 10 years, then the amortization of the avoided costs should be over 10 years in order to ensure that the DER is fully compensated for the value provided. This same principle should be applied to LSRV payments.

Because a DER is simply repaid for the costs it avoids over that amortization period, the payment rate (in $/kWh) should be fixed during this period, though still subject to performance requirements as detailed below in Section C. This looks like a vintaging approach – just as both MTC and E value are vintaged under the Phase 1 Tariff – but actually is simply based on payment of avoided costs over a certain time period.

Obviously, a DER that is developed after an update to the DRV would receive the new, updated DRV for the duration that it is eligible to receive compensation under the Value Stack. Thus the DRV would be updated periodically to provide new values for new DERs, but the value for a particular vintage of DER would remain constant for the amortization period.

[44] CHG&E has presented a ten year levelized cost of the expected transmission and distribution infrastructure upgrade that would be avoided through DER. Central Hudson:" Location Specific Forecasting and Marginal T&D Cost Study", Section 3.3, pg 23 -25.

Under the current Phase 1 framework, the DRV aspect of distribution and transmission compensation for DER generation is not fixed; rather it changes every three years as the utility updates the MCOS for the DRV.[45] This is inappropriate and inaccurate, and also impossible for DER developers, customers, and financiers to accurately forecast.

C. Replace DRV's Top 10 Hour Performance Requirement with Forward-looking Probabilistic Modeling

The current DRV and LSRV mechanisms assess performance based on ten peak hours for the preceding year, but this approach does not align with the much larger number of hours used for actual distribution planning given the uncertainty of when peak load will occur and should not impose unnecessary performance risk for individual DERs.

The Clean Energy Parties propose that the backward-looking top 10-hour performance requirement be replaced with a forward-looking analysis based on probabilistic effective load carrying capability (ELCC) analysis or a similar methodology. This would value the generator based on their contribution to resource adequacy if it reduces the loss of load expectation during any hour or a day. Based on the Distribution System Implementation Plan (DSIP), Central Hudson's probabilistic study outlines a planning risk criteria that specifies the number of hours that forecasted load can exceed the design ratings of components before initiating infrastructure upgrades.[46] These risk tolerances can be as high as 350 hours for rural substations. This suggests the importance of probabilistic modeling and the impact that DER can have outside of the top ten peak hours. If risk tolerance is critical in planning of distribution investments and upgrades as has been suggested by probabilistic studies, and if distribution planning is not based solely on peak demand growth, then DER contributions towards lowering these risks should be valued. DER should be compensated for the benefits it provides to all of the factors that drive infrastructure upgrades and not just the peak demand growth related infrastructure. More than two years ago, the Commission stated that "forecasts should follow a stochastic, or probabilistic,

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[45] March 7, 2017 Order, page 118.

[46] CHG&E Location Specific Forecasting and Marginal T&D Cost Study, Pg. 3, http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7B6ED0A866-16AB-4ED5-9F6E-AA67AA42B878%7D

methodology rather than a deterministic methodology…. Ultimately, quality forecasts, with data as granular as possible, which take into account demand-drivers as explanatory variables, will lead to more optimal investment decisions by the utilities and DER providers."[47]

The time to proceed with better forecasting methodologies – and more accurate DER compensation – is now. To the extent they are not already doing so, the utilities should move to a probabilistic forecasting methodology that identifies the primary hours that drive system investments (potentially covering 300-500 hours). These hours should then be communicated to DER providers via a tariff, allowing DER providers to respond to those price signals by designing and installing new DERs capable of responding during the identified hours.

We recognize that as new DERs are installed to meet system peaks or as new technologies or changes in load behavior emerge, it is possible that the peak period may shift. Indeed, California's time of use rates have been slowly shifting as solar penetration has reduced the traditional day-time peak and resulted in new peaks that occur later in the day. However, the shift in peaks over time does not mean that DERs that perform during the previous peak are no longer providing value; rather, by continuing to perform during the original peak times, these DER are partly responsible for continuing to avoid those historical peaks. The same logic applies to existing RPS resources in California which retain their Time of Delivery adders for delivering midday even though new projects now receive a slight subtractor for the same period of time, a reflection of the fact that RPS resources have now resulted in the hours with generation capacity constraints being later in the day. By contrast, if the window of performance for all DERs were to shift every few years along with changing peaks, then substantial volatility could result from "peak chasing" as both utilities and DER providers continually seek to balance system needs and the price signals sent by the tariff.

Consequently, the better approach would be to initially identify the key 300-500 hours of concern, such as 14:00-18:00 from June through August. Those hours should then be vintaged for each cohort of DERs that is developed during the initial phase. New vintages would be established to send a new signal to new DER if, and as, peaks begin to shift. Because existing

[47] Order Adopting Distributed System Implementation Plan Guidance, Case 14-M-0101, April 20, 2016, p. 30.

DERs would still be providing benefits of lowering net load during the previously-identified hours of concern, the compensation to these DERs during the previously-identified performance period should be maintained. New DERs would be subject to the new performance period requirements. Because such performance periods would be identified in advance, DER could be designed to optimize their peak reduction abilities based on the best available understanding of system needs. In this way, this proposal would be analogous to the utility distribution planning process (or what it should become as envisioned in the aforementioned Commission orders). Our utilities are expected to plan for future distribution peaks and to deploy and then recover the costs for long-lived distribution assets based on the best available information at the time the investment decision is made. This proposal would create the same dynamic for DER—allowing DER providers to invest in the DER that would create the greatest avoided costs based on existing understandings of load patterns, while providing flexibility for the utilities to change their forecasts and the DRV signals for new DERs as system needs evolve over time.

In our view, this approach better aligns performance risk with benefits to the system. Use of a probabilistic forward-looking load analysis reflects the reality that there are many hours that drive system investments, and that DERs that provide load relief during these hours can reduce the amount of distribution infrastructure that utilities must procure. In contrast, use of only ten hours assumes that DERs are only providing benefits during these ten hours, and assigns no benefit to load reductions in other hours. In other words, the 10-hour construct assumes that the past year's ten peak hours are what is driving utility distribution investment and costs, but this is not an accurate representation of the range of hours that drive distribution system investment, nor is it representative of the probabilistic approach to distribution planning that the Commission has instructed the utilities to move toward.

While the number of hours could be more or somewhat less than 300 to 500 hours, it is clear that ten hours are too few, as it raises the risk that a particular DER project will be severely penalized for a localized event, while the distributed nature of DERs makes it unlikely that this localized event would reduce aggregate DER performance. Therefore, in the interim between now and the Phase 2 tariff's completion, we recommend that the Commission consider adopting the Capacity "Alternative Two" 460-peak-hour methodology for all DER currently in development as a proxy for the currently-forecasted system peaks. This methodology defines a set of hours across the Summer season and thus would be a reasonable proxy for our proposal. Although not perfect, this proposal would be far more financeable, would more accurately reflect the stochastic nature of peak load hours, and would be far more likely to achieve the Commission's goal of sending actionable signals for DER deployment through the VDER tariff.

The deflation of the overall marginal cost of service based on already-installed DER is entirely appropriate for evaluating the incremental value that *new* DERs—i.e., DERs that are not included in the baseline—can provide in terms of reducing load. However, this approach is inappropriate for recalculating DRV for existing DERs that were already online (or included in the forecast) at the time the revised MCOS study is conducted. These DER provide clear, ongoing load reduction benefits, but their benefits do not show up as "marginal" benefits under this methodology because they are assumed to be part of the baseline under the existing MCOS methodology. As more and more DER come online and are then included in the MCOS baseline, this flaw in the DRV methodology will result in further and further erosion in DRV values for projects that are still providing load relief but that are assumed to provide no "marginal" relief because of the approach take in the current MCOS study updates. Removing DER from the baseline for purposes of calculating DRV, along with vintaging the DRV value as discussed above, would address this problem in straightforward manner.

VI. SUMMARY

The lack of clarity of these issues, taken together, underscore the necessity of further study through a working group. The DER industry needs greater transparency of the assumptions and methodologies supporting the utilities' MCOS calculations. To truly enact REV's vision of a sustainable grid, the DRV/LSRV value must include all – not just some – of the avoided transmission and distribution benefits that DERs provide. This value must also be financeable and fair, through fixing the value for the length of the tariff and replacing the top 10-hour methodology with forward-looking probabilistic modeling. The Clean Energy Parties are concerned that stakeholder input and the resulting record to date have not adequately examined these issues and we urge the Commission to facilitate the creation of this record before issuing a Phase 2 order.

Thank you.

Respectfully submitted,

/s/
David Gahl
Director of State Affairs, Northeast
Solar Energy Industries Association

/s/
Anne Reynolds
Executive Director
Alliance for Clean Energy New York

/s/
Brandon Smithwood
Policy Director
Coalition for Community Solar Access

/s/
Miles Farmer
Staff Attorney
Natural Resources Defense Council

/s/
Anna Noucas
Acting President
New York Solar Energy Industries Association

/s/
Karl Rabago
Executive Director
Pace Energy & Climate Center

/s/
Nathan Phelps
Regulatory Director
Vote Solar